

**Effects of Temporal Wind Patterns
on the Value of Wind-Generated Electricity at Different Sites
in California and the Northwest**

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INTRODUCTION

Wind power production varies on a diurnal and seasonal basis. In this paper, we use wind speed data from three different sources to assess the effects of wind timing on the value of electric power from potential wind farm locations in California and the Northwestern United States. By “value,” we refer to either the contribution of wind power to meeting the electric system’s peak loads, or the financial value of wind power in electricity markets.

Sites for wind power projects are often screened or compared based on the annual average power production that would be expected from wind turbines at each site (Baban and Parry 2001; Brower et al. 2004; Jangamshetti and Rau 2001; Nielsen et al. 2002; Roy 2002; Schwartz 1999). However, at many locations, variations in wind speeds during the day and year are correlated with variations in the electric power system’s load and wholesale market prices (Burton et al. 2001; Carlin 1983; Kennedy and Rogers 2003; Man Bae and Devine 1978; Sezgen et al. 1998); this correlation may raise or lower the value of wind power generated at each location. A number of previous reports address this issue somewhat indirectly by studying the contribution of individual wind power sites to the reliability or economic operation of the electric grid, using hourly wind speed data (Fleten et al.; Kahn 1991; Kirby et al. 2003; Milligan 2002; van Wijk et al. 1992). However, we have not identified any previous study that examines the effect of variations in wind timing across a broad geographical area on wholesale market value or capacity contribution of those different wind power sites. We have done so, to determine whether it is important to consider wind-timing when planning wind power development, and to try to identify locations where timing would have a more positive or negative effect.

The research reported in this paper seeks to answer three specific questions:

- 1) How large of an effect can the temporal variation of wind power have on the value of wind in different wind resource areas?
- 2) Which locations are affected most positively or negatively by the seasonal and diurnal timing of wind speeds?
- 3) How compatible are wind resources in California and the Northwest (Washington, Oregon, Idaho, Montana and Wyoming) with wholesale power prices and loads in either region?

The latter question is motivated by the fact that wind power projects in the Northwest could sell their output into California (and vice versa), and that California has an aggressive renewable energy policy that may ultimately yield such imports.

We also assess whether modeled wind data from TrueWind Solutions, LLC, can help answer such questions, by comparing results found using the TrueWind data to those found using anemometers or wind farm power production data.

This paper summarizes results that are presented in more detail in a recent report from Lawrence Berkeley National Laboratory (Fripp and Wiser 2006). The full report is available at <http://eetd.lbl.gov/EA/EMP/re-pubs.html>.

METHODS

We used three wind datasets to estimate the time-varying wind power available from California and Northwestern wind sites:

- 1) **TrueWind:** TrueWind Solutions, LLC (now AWS Truewind) provided modeled wind speeds for every cell on a 200-meter grid in California and a 400-meter grid in the Northwest (Brower 2002a, 2002b). Wind speeds were given for every month-hour combination in California and every season-hour in the Northwest.
- 2) **Anemometers:** We used hourly anemometer data from Kenetech, Inc. (167 sites), the Bonneville Power Administration (6 sites) and the DOE Candidate Site program (7 sites).
- 3) **Actual Wind Farm Production:** We used historical hourly power production data from the Altamont, Tehachapi and San Geronio areas in California and monthly power production data from several more sites in California and the Northwest.

We used the wind data with electricity load and wholesale electricity price series for California and the Northwest to estimate the effects of wind timing on the value of wind-generated electricity at locations throughout California and the Northwest. The effects of timing were measured by two approaches, yielding three key metrics for each location.

- **Capacity Metric:** Power planners often need to estimate the amount of additional year-round electricity load that a new generator will allow the system to meet reliably. The most widely accepted measure of the “capacity value” of a new generator is its Effective Load-Carrying Capacity (ELCC) (Kahn 1991; Kirby et al. 2003; Milligan 2002). The ELCC of a new generator depends on the reliability and timing of both the new generator and the other generators already in the system, as well as the timing of the electric load. A formal ELCC analysis requires proprietary data about the generation system, as well as computational resources that would make it prohibitive for estimating the capacity value of wind turbines located at millions of different grid cells. For our analysis, we instead used a simplified measure of the capacity contribution, which we called the “load-weighted capacity factor.” This is calculated as the capacity factor of the wind power plant during the top 10 percent of peak-load hours during the year. Some studies note that this value is often within a few percentage points of the true ELCC for a plant, although uncertainty remains (Kirby et al. 2003: 25-26; Milligan and Parsons 1997; Milligan and Porter 2005). In this paper, we report the difference between the load-weighted capacity factor at each location, and the annual average capacity factor at the same location, which indicates the effect of wind timing on the capacity value at each wind site.
- **Price Metrics:** We estimated the annual wholesale market value of a flat block of power and the annual market value expected from the time-varying wind speeds found at each location (when correlated with time-varying wholesale market prices). The difference between these two values reflects the potential effects of temporal wind patterns on the wholesale market value of power from a wind turbine. These values were calculated using (1) historical wholesale power prices, and (2) forecasted wholesale power prices.

Historical loads for California and the Northwest were based on FERC Form 714 filings by electric utilities for 2000–04. Historical wholesale prices for California were the average of the

CalPX prices for the NP15 and SP15 hubs for 7/98–6/99¹, and historical prices for the Northwest were based on the Dow Jones hourly prices for the Mid-C hub for 5/02–4/05. Our forecast price series for California was the average of hourly forecasts for all California hubs for 2006–13, provided by the California Energy Commission on March 13, 2004 (Klein 2004). Our price forecast for the Northwest was the average of the Northwest Power and Conservation Council's base-case hourly forecasts for the Mid-C hub for the years 2006–2025, generated on September 2, 2005 (King 2005).

For some of the analysis that follows, we grouped the anemometers in our dataset into separate “wind resource areas,” about 40 km across, in order to estimate the local effects of wind timing in the areas that are most likely to receive wind power development. These areas are shown in Figures 1 and 2.

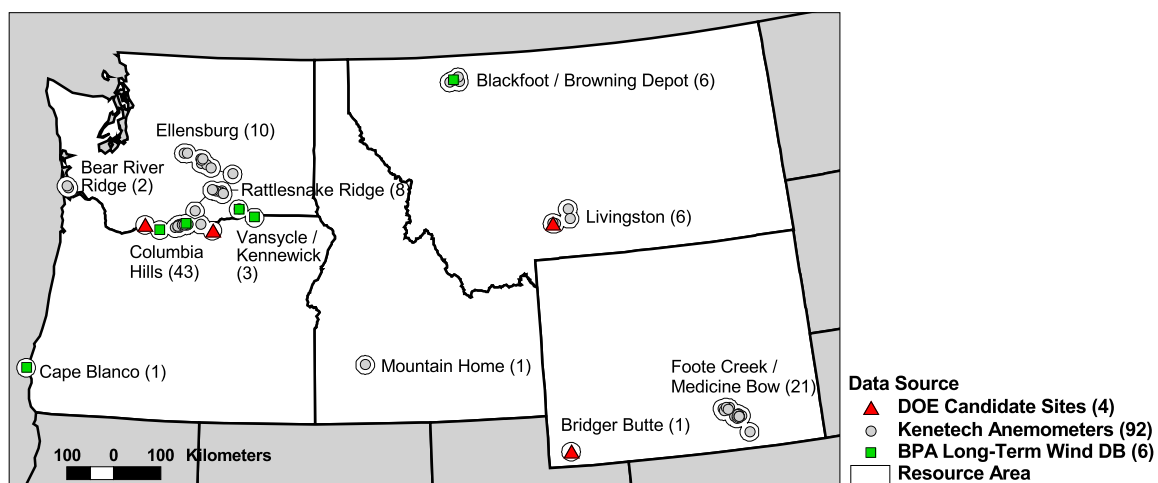


Figure 1. Locations of Anemometer Towers and Resource Areas in the Northwest

¹ The earlier, shorter period was chosen for California because it provided a full year of market data before the power crisis of 2000–01 and the subsequent restriction of wholesale markets.

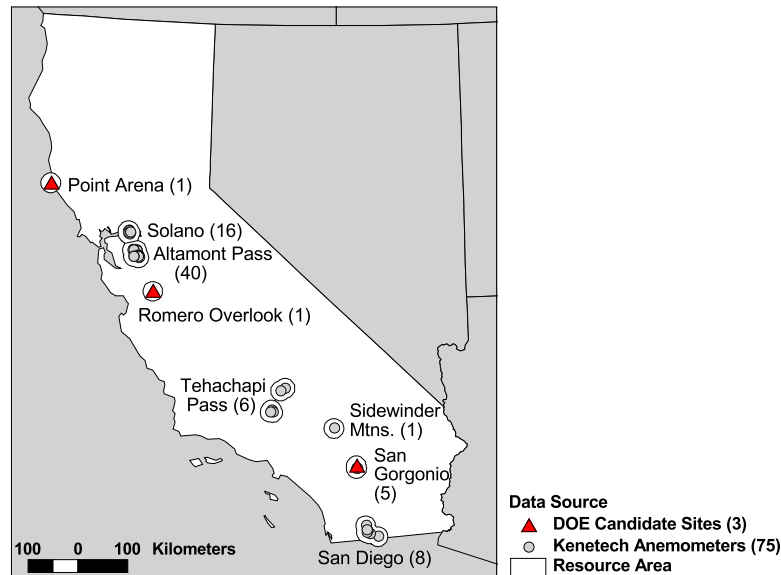


Figure 2. Locations of Anemometer Towers and Resource Areas in California

DATA LIMITATIONS

Several factors may reduce the accuracy of our estimates of turbine-height wind speeds from the TrueWind, anemometer and production datasets. These factors could reduce the quality of fit between the datasets, and make it difficult to say which dataset gives a more accurate picture of hub-height wind patterns.

- **Modeling Uncertainty.** The TrueWind wind-speed estimates and diurnal profiles are based on a computerized atmospheric model, which is subject to uncertainty due to limitations in its resolution and the number of atmospheric processes it can incorporate.
- **Wind Shear.** We estimated wind speeds at a 70-meter hub height from anemometer measurements taken at lower elevations by way of a relatively simple power law relationship, with fixed exponents of 0.09 during the day and 0.20 at night at all locations. This approximation neglects the fact that wind shear can change with time of year and terrain. We also applied no correction to the available wind farm production data, which came from a variety of heights.
- **Limitations of Historical Data.** TrueWind estimated wind speeds by sampling from a 15-year period to estimate long-term average wind speed and wind power at each grid cell. However, our anemometer and wind farm production data come from specific historical periods, and cover differing lengths of time at each site, so they may not reflect the same meteorological conditions as the TrueWind dataset. This concern is reduced by the fact that we use only month-hour or season-hour averages of wind data for our analysis.
- **Anemometer Location.** The locations reported for anemometers in our dataset may be incorrect by a few kilometers in some cases, causing them to be compared to the wrong TrueWind grid cell.
- **Effective Ground Level Differences.** The wind speeds reported by TrueWind were given at heights of 50 or 70 meters above “effective ground level” (Brower 2002a, 2002b). In dense forest, this is relative to the canopy height, which may be a significant distance above the true

ground level. We did not correct these effective heights to true heights before comparing them to observations.

REGION-WIDE RESULTS FROM TRUEWIND DATA

Using the TrueWind data, we found that temporal wind patterns at different locations could have a large effect on the average power output during hours of peak electricity demand, and a smaller but not insignificant effect on the annual wholesale market value of wind power, based on historical and forecast wholesale-market electricity prices.

Figure 3 summarizes the findings from the TrueWind data for all grid cells in California and the Northwest with annual average winds equivalent to Class 4 or greater (corresponding to sites usually considered economically viable for wind power development). The central bar of each marker in Figure 3 shows the median effect of wind timing on each measure of wind value, based on the TrueWind data. The lower and upper bars show the range of effects between the 10th and 90th percentile of Class 4+ grid cells in each region. It should be noted that these results include many locations that are inaccessible or otherwise unsuitable for wind farm development because of land use or land form constraints (*e.g.*, national parks or high mountain ridges).

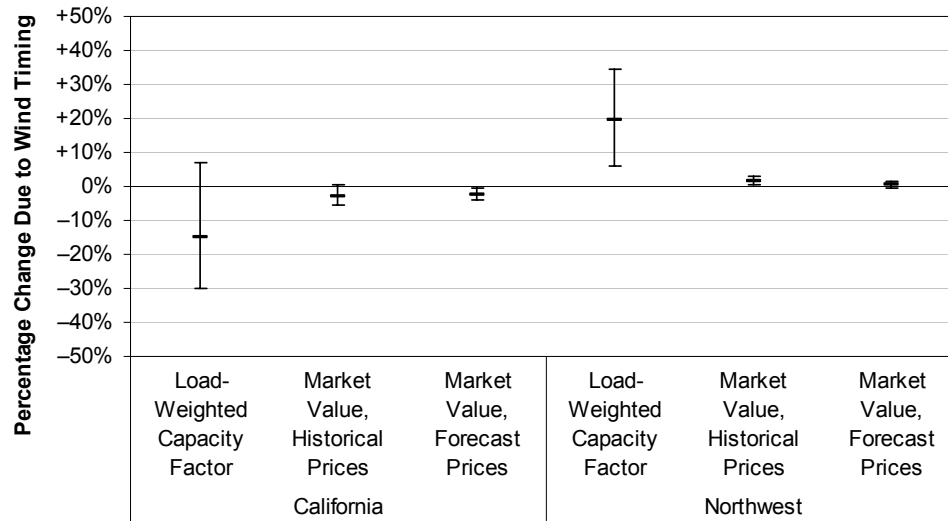


Figure 3. Effects of Wind Timing on Load-Weighted Capacity Factor and Annual Market Value at Class 4+ Grid Cells in California and the Northwest (Median, 10th and 90th Percentiles)

The TrueWind data indicate that the best- and worst-timed of the windy Northwestern grid cells have *peak-hour capacity factors* that range from 6 to 34 percent above their annual average capacity factors (at the 10th and 90th percentiles), with a median of 20 percent above. Windy locations in California have peak-hour capacity factors ranging from 7 percent above to 30 percent below their annual average capacity factors, with a median of 15 percent below.

According to the TrueWind data, the worst-timed Northwestern sites have a *wholesale market value* approximately equal to what would be obtained if their power output was completely uncorrelated with electricity demand, while the best-timed sites would have a market value about

3 percent more than this, based on the Northwest's historical prices. When forecast prices are used, the value of power at Northwestern sites ranges from about 1 percent below to 2 percent above the value of a flat block of power. California wind sites appear to match California markets somewhat worse, with market values ranging from an amount equal to what the wind site would earn with uncorrelated power output, down to about 4-6 percent below this, based on California's historical or forecast prices.

Figure 4 shows the geographic distribution of the effect of wind timing at Class 4+ cells, according to the TrueWind dataset, when using Northwestern wind power with the Northwest's historical prices or California wind power with California's historical prices. Wind timing appears to have a neutral or positive effect at most Northwestern high-wind locations. In California, wind timing appears to improve the value of power from the northernmost coast, but reduces the value of power from high-wind locations elsewhere in the state.

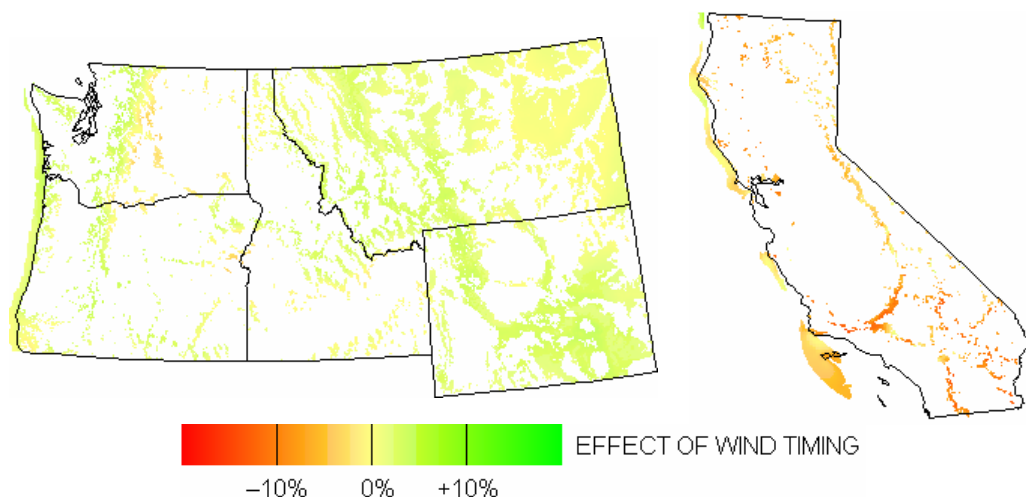


Figure 4. Percentage Change in Market Value of Power due to Temporal Wind Patterns at all Class 4+ Grid Cells in the Northwest and California, Based on Local Historical Power Prices

REGION-WIDE RESULTS FROM ANEMOMETER DATA

Figure 5 shows the range of each of the three wind value metrics, when using the available anemometer measurements in each region. We have also shown the range found using TrueWind data for grid cells at the same locations. Although these findings are not as geographically comprehensive as those shown above, they allow us to compare the results from the TrueWind and anemometer data at similar locations. Anemometers in our dataset are generally concentrated in the most promising areas for wind development, so the results found at these locations may also be more representative of the effects of wind timing in the areas where wind farms are likely to be built.

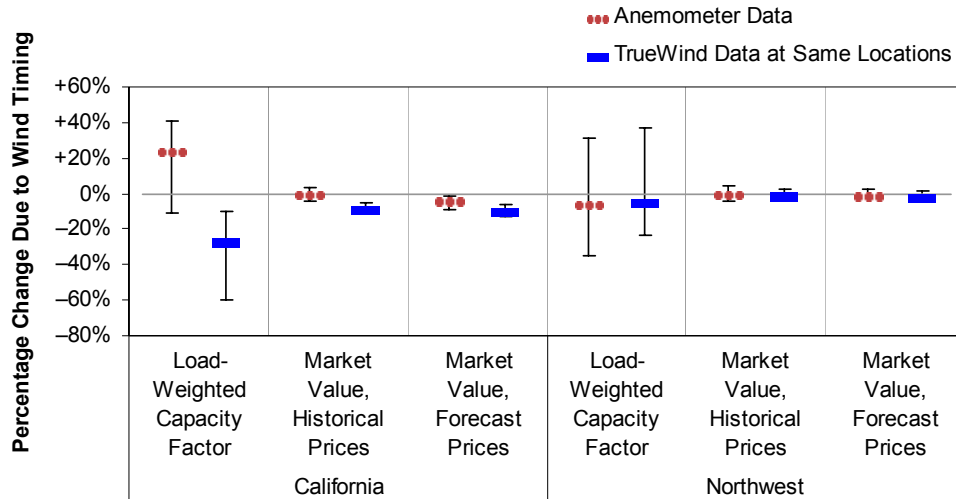


Figure 5. Comparison Between Wind-Value Measures Derived from Anemometer Measurements and Measures Derived from TrueWind Data for the Same Locations (Median and 10th–90th Percentile Range)

In the Northwest, by either the anemometer or TrueWind data, wind resources at the anemometer sites appear to be about neutrally matched to historically winter-peaking electrical loads and historical and forecast wholesale market prices.

The two datasets show worse agreement in California. The TrueWind data suggest that wind timing generally reduces the value of power at California anemometer sites, while the anemometer data suggest that wind timing has a more neutral or positive effect at those same locations. This difference appears to be caused by disagreement about the diurnal timing of summer winds in some California wind resource areas, which is discussed further in the next section. Despite this disagreement, the two datasets generally agree on the size of the effect of wind timing (that is, the difference between the best- and worst-timed sites).

The TrueWind results for all California Class 4+ grid cells, shown in Figures 3 and 4, include summer-peaking coastal and mountain locations that make them somewhat more optimistic than the TrueWind results at the anemometer locations used for Figure 5. Figure 3 also shows better results than Figure 5 for load-weighted capacity factors in the Northwest, probably because of the inclusion of winter-peaking mountain sites where anemometers have not been placed and wind resource development is unlikely.

TEMPORAL WIND PATTERNS FROM TRUEWIND, ANEMOMETER AND PRODUCTION DATA

Before we present the effects of wind timing in each of the resource areas defined earlier, we briefly compare the wind patterns reported by our three datasets for these areas. We find that there is generally good agreement between the TrueWind and anemometer data about the times of year when wind speeds peak in each resource area. These two datasets are also in reasonably good agreement about winter-time diurnal profiles in each resource area, which tend to be relatively flat. However, in some resource areas, the TrueWind and anemometer datasets show significant disagreement about summertime diurnal wind profiles. These disagreements can in

turn cause significant disagreement about the effect of wind timing on the value of power when summer-peaking load or price series are considered. We note three distinct types of disagreement about summer diurnal wind speed profiles:

- 1) In a number of resource areas, the TrueWind data show a deeper, longer dip in summer daytime wind speeds than the anemometer data, reducing the amount of power available on summer afternoons (Figure 6a). We observe this type of disagreement in two of the eleven Northwestern resource areas (Ellensburg and Rattlesnake Ridge), and four of the eight California resource areas (Solano, Altamont Pass, Romero Overlook and San Geronio).
- 2) In several resource areas, the TrueWind data show summer winds rising steadily from early afternoon until they peak at midnight, while the anemometer data show winds rising from late morning and peaking around 6 pm (Figure 6b). This type of disagreement also causes the TrueWind data to report that less power is available to meet summer-afternoon-peaking electricity loads. We noted this effect in the Ellensburg and Rattlesnake Ridge areas in Washington, and in the Tehachapi, Sidewinder and San Diego areas in California.
- 3) In the Blackfoot and Livingston areas in Montana and the Mountain Home area in Idaho, the weak summertime diurnal profiles from TrueWind and the anemometers are nearly reversed (Figure 6c). In these areas, anemometers show morning lulls and afternoon peaks, while the TrueWind data show morning peaks and afternoon lulls, again reducing the amount of wind power available on summer afternoons.

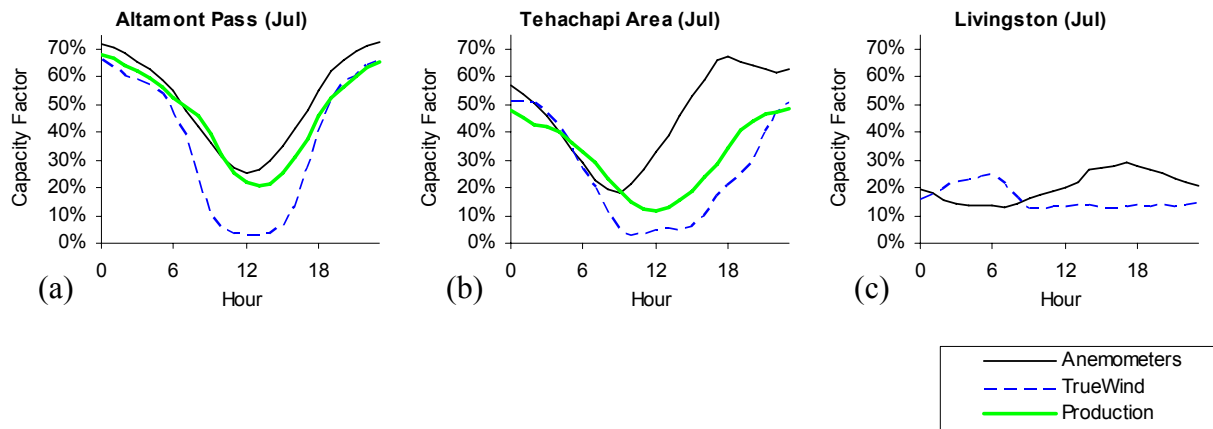


Figure 6. Diurnal Average Capacity Factor for Three Resource Areas from Anemometers and TrueWind Data at the Same Grid Cell, and Production Turbines in the Same Region

The historical production data from operating wind projects in the Tehachapi and San Geronio areas appear to agree more with the TrueWind data, while the historical production data for Altamont Pass more closely resemble the anemometer data. However, these comparisons are of limited value in resolving the disagreement between the TrueWind and anemometer data, because the wind turbines in these locations are mounted at relatively low tower heights.

Some of the difference in temporal wind speed patterns between the anemometers and TrueWind data may be due to temporal variations in wind shear which result from surface heating or strong near-surface flows on summer days. These processes could increase power production at lower levels during the day and reduce it at night, relative to the upper-level winds. The height of the

turbines at wind farms in California is often between the anemometer heights (20-30 m) and the TrueWind reference height (50 m in the Northwest and 70 m in California), so the intermediate estimates of the effects of wind timing from the wind farm production data are consistent with this hypothesis. However, much of the difference could also be due to shortcomings of the TrueWind model or inconsistencies in the date ranges or locations of the anemometer and TrueWind data. More anemometer or production data from tall towers are needed before we can fully judge whether the TrueWind data provide an accurate picture of the effects of wind timing on the value of power at some wind resource sites, especially those with summer-peaking wind speeds.

EFFECTS OF WIND TIMING IN EACH RESOURCE AREA

In this section, we consider the effects of wind timing on the value of wind power from each of the resource areas where anemometers were placed, rather than looking at region-wide results, as we did in earlier sections. We also compare the timing of wind in each resource area to both the California and Northwest market data, rather than assuming that all wind power is used in the same region where it is produced.

In our full report (Fripp and Wiser 2006), we show the effects of wind timing using historical electricity loads and historical and forecast wholesale market prices. For brevity, here we discuss only the results found using historical wholesale prices. The Northwest's historical wholesale prices generally peak on winter mornings and evenings, and our results using this series are similar to those found using the Northwest's historical electricity loads or forecast electricity prices. California's historical wholesale prices peak on summer afternoons, and this data series also yields similar results to those found using California's historical loads or forecast prices, which also peak on summer afternoons. Variations in load-weighted capacity factor across different potential wind sites are about seven times greater than variations in market value, but the relative standing of different resource areas remains the same.

Figure 7 shows the effects of wind timing on the value of wind power from each of the resource areas where anemometers were placed, when considering historical Northwestern wholesale power prices. The red circles and blue rectangles indicate the median effects among all anemometer locations in each resource area, as calculated using either anemometer data or TrueWind data at the same sites. For the Altamont, Tehachapi and San Geronio resource areas, we also show the effects calculated using the total output from all wind farms in each region. There is good agreement between the anemometer and TrueWind datasets when assessing the value of power using the Northwest's winter-peaking wholesale prices. Seven or eight out of eleven Northwestern resource areas appear to be at least somewhat positively matched to the Northwest's winter-peaking wholesale prices, while only 1–3 of the eight California sites show a positive match, which is weak at best.

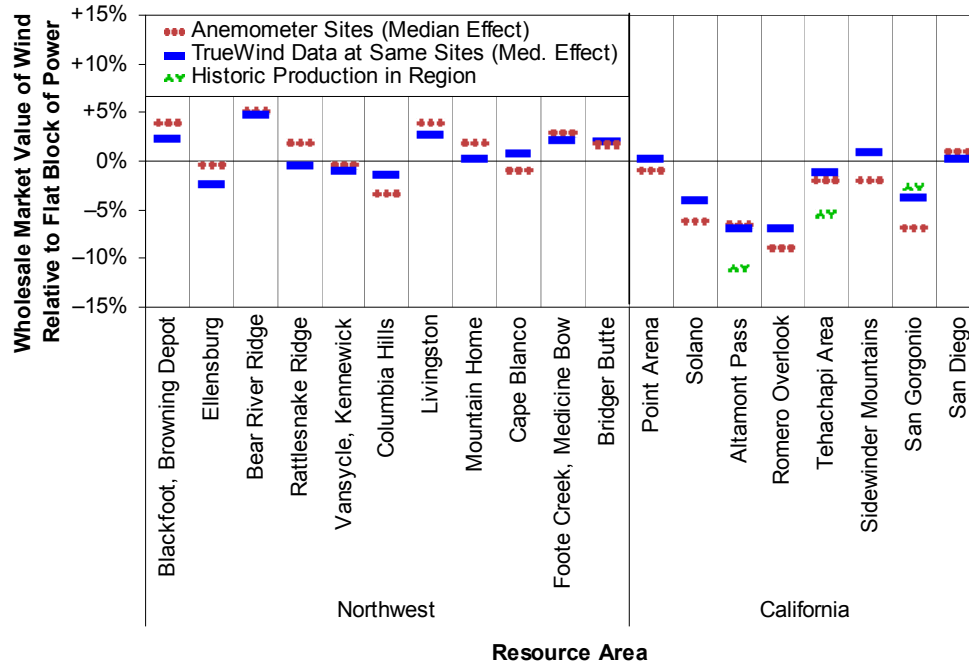


Figure 7. Median Effects of Timing on Market Value at Anemometer Sites in Each Resource Area, Based on Historical Northwestern Prices

Figure 8 shows the effects of temporal wind patterns on the value of wind power from each resource area, using California's historical wholesale prices. California's wholesale power prices peak strongly on summer afternoons. Consequently, the TrueWind and anemometer data show significant disagreement about the effects of wind timing in the same places where they disagree about summer afternoon wind speeds, particularly in California's major existing wind resource areas. Where available, the actual historical power production data yield results that are intermediate between those found using the other two datasets.

According to the anemometer data shown in Figure 8, about a third of the Northwestern resource areas and half of the California resource areas are positively matched to California's summer-afternoon-peaking historical prices. However, TrueWind data at the same locations suggests that only a quarter of the Northwestern resource areas and no California areas are positively matched to California's historical prices. If both the anemometer and TrueWind data are correct, and the differences are due to their different elevations, then it is possible that the timing of power production will worsen as new wind farms use taller towers. This effect could offset some of the gains in peak-hours capacity factor or market value that would otherwise be expected due to the improved wind speeds at the higher elevations.

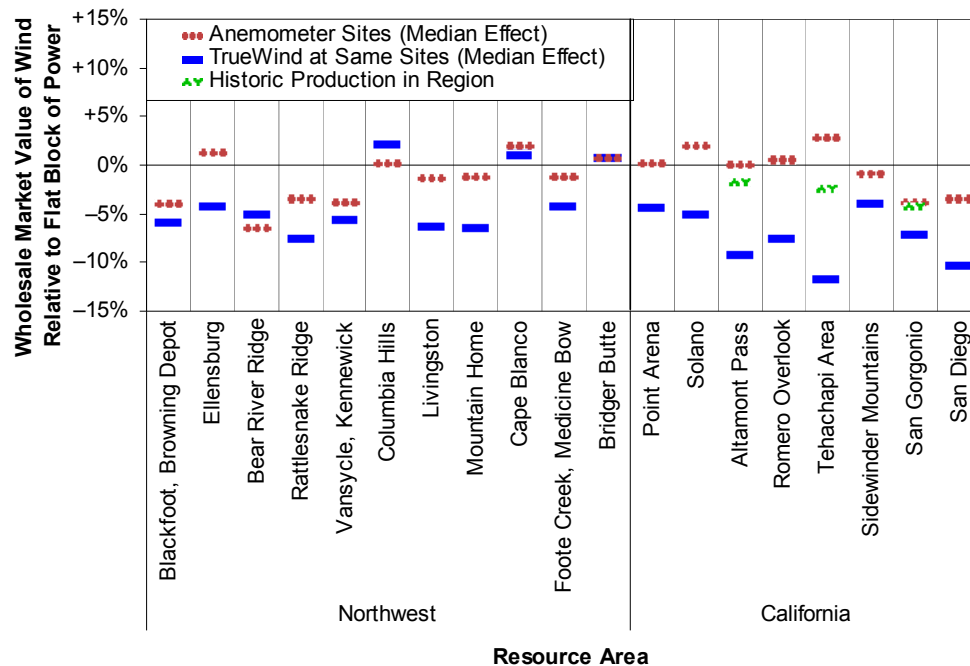


Figure 8. Median Effects of Timing on Market Value at Anemometer Sites in Each Resource Area, Based on Historical California Prices

CONCLUSIONS

Despite variations in our results caused by disagreements in our underlying wind speed datasets, the analyses presented earlier hold several important conclusions.

Temporal patterns have a moderate impact on the wholesale market value of wind power.

The best-timed wind power sites have a wholesale market value that is up to 4 percent higher than the average market price, while the worst-timed sites have a market value that is up to 11 percent below the average market price. This is a relatively narrow range, and suggests that the timing of wind is not likely to severely degrade the market value of wind power.

Temporal patterns have a substantial impact on the capacity factor during peak hours.

The best-timed wind sites could produce as much as 30–40 percent more power during peak hours than they do on average during the year, while the worst timed sites may produce 30–60 percent less power during peak hours. It would be valuable to develop better estimates of the effective load-carrying capacity (ELCC) at different wind sites, in order to better assess the effect of wind timing on the capacity credit for wind farms.

Northwestern markets appear to be well served by Northwestern wind and poorly served by California wind; results are less clear for California markets.

Both the modeled TrueWind data and the anemometer data indicate that many Northwestern wind sites are reasonably well-matched to the Northwest's historically winter-peaking wholesale electricity prices and loads, while most California sites are poorly matched to these prices and loads. However, the TrueWind data indicate that most California and Northwestern wind sites are

poorly matched to California's summer-afternoon-peaking prices and loads, while the anemometer data suggest that many of these same sites are well matched to California's wholesale prices and loads.

TrueWind and anemometer data agree about wind speeds in most times and places, but disagree about California's summer afternoon wind speeds: The TrueWind data indicate that wind speeds at sites in California's coastal mountains and some Northwestern locations dip deeply during summer days and stay low through much of the afternoon. In contrast, the anemometer data indicate that winds at these sites begin to rise during the afternoon and are relatively strong when power is needed most. At other times and locations, the two datasets show good agreement. This disagreement may be due in part to time-varying wind shear between the anemometer heights (20-25m) and the TrueWind reference height (50m or 70m), but may also be due to modeling errors or data collection inconsistencies. These findings suggest that it is reasonable to use TrueWind's modeled data to assess the effect of temporal patterns in wind speeds, especially when the value of electricity does not peak sharply in the summer. However, more data from tall anemometer towers or operational wind farms are needed to resolve differences between the datasets for summer afternoons.

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